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SUMMER 2007 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

DRAFT STAFF REPORT

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Arnold Schwarzenegger, *Governor*

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Denny Brown
Principal Author

Albert Belostotsky
Contributing Author

Denny Brown
Project Manager

David Ashuckian
Manager
ELECTRICITY ANALYSIS OFFICE

Sylvia Bender
Acting Deputy Director
ELECTRICITY SUPPLY ANALYSIS DIVISION

B. B. Blevins
Executive Director

ABSTRACT

This report provides a summary of the California Energy Commission staff's current assessment of the capability of the physical electricity system to provide power to meet electricity demand in specific geographic areas within California. It also documents key assumptions and methodologies used to develop an assessment of physical resources and requests input from interested parties for future analytical work.

KEYWORDS

Supply and demand outlook, probability, operating reserve, loss of load, demand, forced outage, generation, net interchange, demand response, interruptible load, reserve margin

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Dave Ashuckian
Barbara Crume
Joseph Gillette
Richard Jensen
Connie Leni
Daryl Metz
Adam Pan
Marc Pryor
Angela Tanghetti
David Vidaver
Jim Woodward

Demand Analysis Office
Tom Gorin
David Hungerford
Lynn Marshall

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INTRODUCTION AND SUMMARY

The *Summer 2007 Electricity Supply and Demand Outlook* provides a summary of the California Energy Commission (Energy Commission) staff's current assessment of the capability of the physical electricity system to provide power to meet electricity demand in specific geographic areas within California. The report does not include an evaluation of the condition of the electricity market, specific contractual details or the adequacy of any individual utility.

This outlook includes an examination of four regions - California Statewide, California Independent System Operator (California ISO) Control Area, California ISO North of Path 26 (NP26), and California ISO South of Path 26 (SP26). The California ISO Control Area is divided into Northern and Southern California because there are transmission constraints south of the transmission segment known as Path 26, which limit the transfer of electricity from north to south. Northern California includes the Pacific Gas and Electric (PG&E) service area, participating municipal utilities and Energy Service Providers (ESPs) in Northern California served by the California ISO. Southern California includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Southern California municipal utilities and ESPs that participate in the California ISO. The outlook is base on the *Staff Forecast of 2007 Demand* developed in June 2006 for forecasted loads in each region.

This analysis was prepared in coordination and consultation with the California Public Utilities Commission (CPUC), the California ISO, utilities and other stakeholders. An Integrated Energy Policy Report (IEPR) Committee workshop will be held on May 24, 2007 to receive stakeholder and public comments on the staff draft report. The staff is also seeking input on the proposed analysis for the *Summer 2008 and Five -Year Electricity Supply and Demand Outlook* scheduled to be published this fall.

Format and Methodology Changes from 2006 Report

This assessment includes several changes in format and methodology as a result of the staff's continuing effort to develop probabilistic assessments to enhance the tables we have historically completed. The deterministic tables only provide line-by-line analysis to the planning reserve calculation. The expected and adverse operating reserve margin scenarios have been removed from the 2007 outlook. The staff believe that a probabilistic approach more accurately represents the complete range of demand possibilities, as well as generation and transmission forced outage occurrences. These probabilities are calculated using historical data to assess the possibility of multiple adverse conditions occurring simultaneously.

The 2007 outlook introduces probabilistic studies for the entire California ISO Control Area and the NP26 portion of the California ISO Control Area, in addition to the SP26 region included in the 2006 outlook. The California Statewide outlook is only presented in a deterministic format because the statewide system is composed of multiple control areas and does not operate as a single entity.

Summary of Results

The 2007 Summer Outlook is summarized below in both the deterministic and probabilistic formats. Table 1 provides the planning reserve margins for each of the four regions. The planning reserve margin is calculated in a similar manner as in CPUC resource adequacy proceedings and is the margin by which the capacity from net generation, demand response and interruptible load programs exceeds the 1-in-2 demand forecast. The region with the lowest planning reserve margin for 2007 is the portion of the California ISO Control Area located South of Path 26, although the margin exceeds the 15-17 percent planning reserve criteria required by the CPUC. Appendix A provides detailed monthly tables and a line-by-line description of the supporting information and assumptions used in the planning reserve margin calculations.

Table 1: 2007 California Electricity Outlook
(Megawatts)

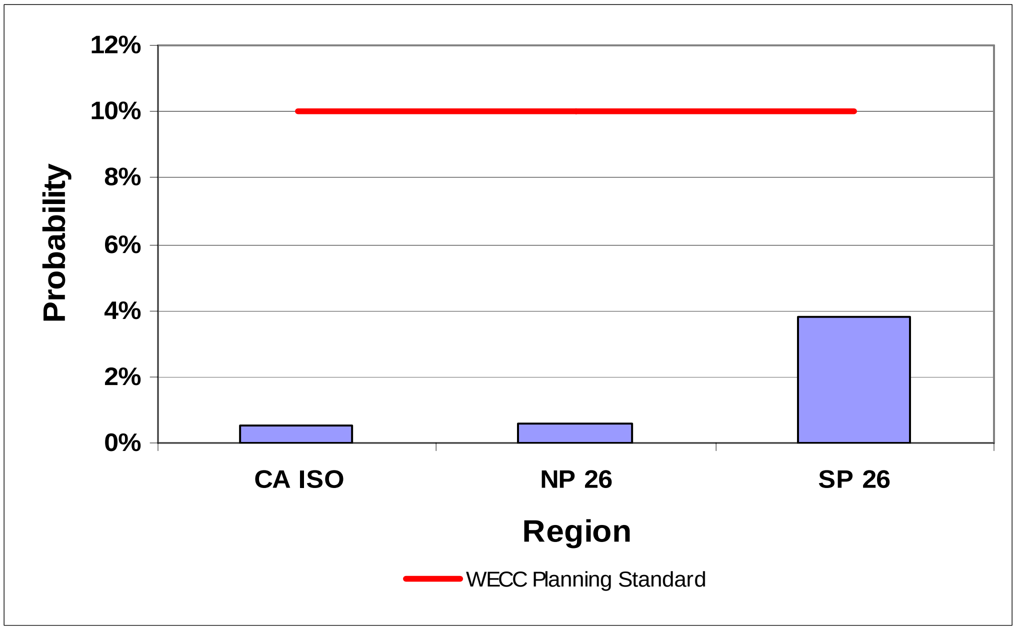
		NP 26	SP 26	CA ISO	Statewide
1	Existing Generation (Summer Derated)	24,417	21,848	46,265	57,897
2	Retirements (Known)	0	0	0	0
3	High Probability CA Additions (Summer Derated)	74	429	503	656
4	Net Interchange	500	10,100	10,600	13,118
5	Total Net Generation	24,991	32,377	57,368	71,671
6	1-in-2 Summer Temperature Demand (Average)	21,100	28,374	48,289	60,344
7	Demand Response	322	202	524	524
8	Interruptible/Curtailable Programs	316	1,087	1,403	1,603
9	Planning Reserve	21.5%	18.7%	22.8%	22.3%

Figure 1 displays the staff estimate of the probability of involuntary load curtailment in the California ISO Control Area and the two sub-regions on the peak day for the summer 2007 period. The SP26 region has the highest probability of involuntary load curtailment or rotating outages. The corresponding Loss of Load Probability (LOLP) for the region is 3.5 percent, which is significantly lower than the Western Electricity Coordinating Council (WECC) acceptable planning criteria of one loss of load event every 10 years, equivalent to a 10 percent LOLP. Staff estimates the California ISO Control Area and NP26 both have an LOLP of less than 1 percent for summer 2007.

Utilities that are not members of the California ISO Control Area appear to have adequate resources to meet expected electricity demand this summer. These public utilities include Los Angeles Department of Water and Power (LADWP), Burbank

Water and Power, Glendale Water and Power, and Imperial Irrigation District in Southern California and Sacramento Municipal Utility District (SMUD), Modesto Irrigation, Redding, Roseville Electric, and Turlock Irrigation in Northern California.

Figure 1: Loss of Load Probability



Next Steps

The analytic process for the *Summer 2008 and Five-Year Electricity Supply and Demand Outlook* is currently underway with plans to publish the results by this fall. The outlook will use the 2008 Peak Demand and long-run demand forecasts once they have been subject to public review as part of the 2007 IEPR proceedings.

The staff is requesting stakeholder input on topics that may be included in the report. A few topics for possible study have already been identified and include:

- Probabilistic assessment of wind variability.
- Develop randomization factors for additional demand variables to enable a probabilistic long-term assessment.
- Modeling the 3,000 Megawatt (MW) Path 26 interchange assumption correctly.
- Study planning reserve margins to determine the associated loss of load risk using 15 percent, 17 percent and 2008 projected planning reserve margins.
- Potential impacts of environmental issues, including greenhouse gas reduction and once-through cooling limitations.

Parties are asked to provide comments regarding the *Summer 2007 Electricity Supply and Demand Outlook* or proposed topics to include for future study, both orally at the May 24, 2007 workshop and in writing. Comments submitted before the workshop will be used to facilitate the discussion. For written comments, please include the docket number ***No. 06-IEP-1J*** and indicate ***2007 IEPR – Supply Demand Outlook*** in the subject line or first paragraph of your comments.

Regional Probabilistic Assessments

Background of Probabilistic Assessment

The staff is continuing with its development of a full probabilistic assessment to enhance the deterministic tables provided in previous reports. In the staff's deterministic tables presented in previous year's outlooks, reserve margins were estimated for two operating scenarios: expected (1-in-2) and adverse (1-in-10) conditions. However, in system planning, neither supply nor demand can be predicted with absolute accuracy or determined on a single point forecast. Future conditions that determine load, as well as availability of supply, can be better predicted within a range of uncertainty. Studies based just on the most likely set of conditions fall short of looking at the full range of possible demand and the fluctuation in supply capabilities. Likewise, studies based on adverse conditions are still limited in scope and may overestimate the exposed risk to these events.

As the summer 2006 showed, the peak load in the Northern California was significantly higher than projected in the 1-in-10 forecast and was not captured by the deterministic methodology. This experience demonstrated that the single- or two-point deterministic evaluations are not sufficient; therefore a wider range of factors and future conditions should be evaluated to exclude unexpected contingencies in the forecast of supply adequacy.

The observed performance of the electricity system over time and an extensive record of temperature conditions that are correlated to actual demand has allowed the Energy Commission staff to develop probability of occurrence measures for each of the major uncertainty factors. Incorporating the probability of occurrence to an electricity supply assessment provides a better representation of the fluctuations in the system and measures the risks of actually encountering an electricity emergency event based on historical data.

The Supply Adequacy Model (SAM) is a forecasting tool that assesses the balance of power supply and demand for a power system throughout the WECC regions. SAM was originally developed at the Energy Commission in 1998. For this analysis, the staff needed to modify SAM to analyze a specific region. This modified version of the SAM is referred to as SAM-A. The SAM-A was designed to be a relatively fast and simple analytical tool with the capability of incorporating uncertainty variables. The probabilistic approach for analyzing supply adequacy is an important feature of SAM-A, which differs from other deterministic models.

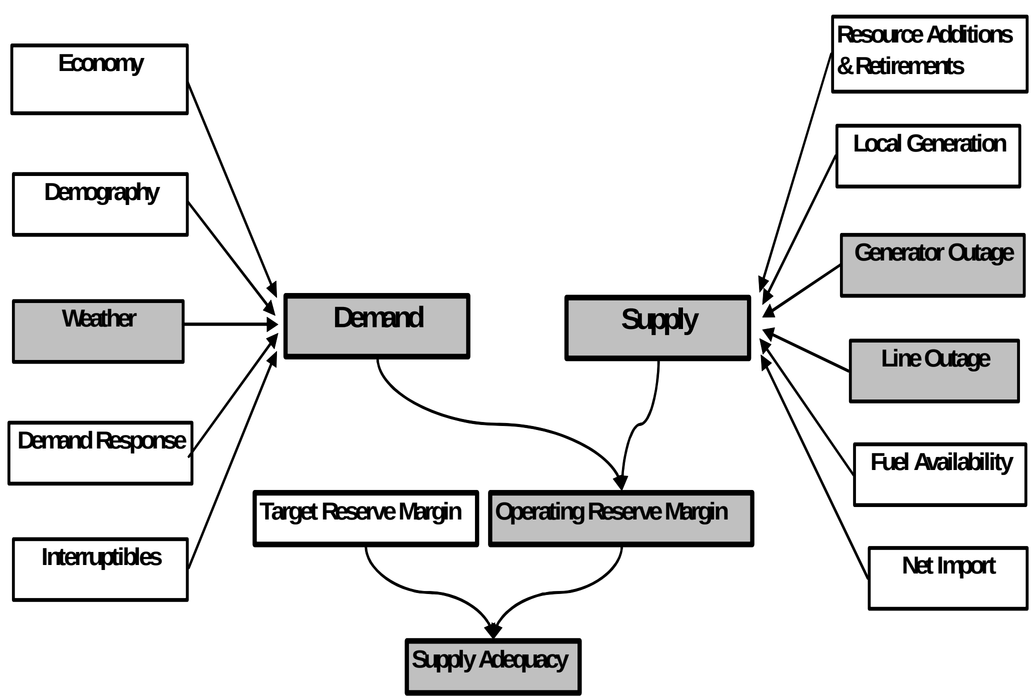
In the initial probabilistic study, the staff included the probabilities of high demand and generation forced outages in the Southern California (SP26) portion of the California ISO Control Area. The SP26 region was selected because it had the lowest planning reserve margin and presented the highest probability of not meeting operating reserve requirements. *The Summer 2006 Electricity Supply and Demand*

Outlook incorporated the probability of forced outages of transmission lines in the SP26 region. In this 2007 report, the staff added analysis of the entire California ISO Control Area and the NP26 sub-region using the same three probabilistic variables of demand, generation outages and transmission outages used in the 2006 report.

There are a number of variables to consider when assessing supply adequacy of a system. This probabilistic assessment evaluates the complete range of demand scenarios based on weather variation, as well as generation and transmission outage occurrences based on historical data. The staff developed multiple cases of different resource availability, transmission capabilities and demand-varying scenarios using the Monte Carlo method to determine physical supply adequacy. Figure 2 shows the major factors used to develop the 2007 outlook. The probabilistic methodology was applied to the factors in the highlighted boxes in the chart.

The staff is continuing to expand the probabilistic methodology and will continue to randomize the effects of additional factors when more information is made available from stakeholders. The following description is an explanation of how the probabilistic methodology was applied to analyze the SP26 region. The analytical process is the same for all three regions, but SP26 was selected for illustrative purpose because it has the highest risk of firm load curtailments.

Figure 2: Major Factors Affecting Supply Adequacy



Probability of Demand

The probability of demand calculations are based on the most recent adopted Energy Commission demand forecast[1] as updated for the Investor Owned Utility (IOU) portion in June 2006[2] .Complete documentation of assumptions and methodologies are included in the above reports.

Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a buildup of high temperatures over several days. To incorporate the effect this buildup of heat has on peak demand, the staff calculated a weighted average temperature (max 631). The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three day period.

The staff used the max 631 to develop a temperature response adjustment for varying degrees of hotter-than-average temperatures. The staff estimated the relationship between temperature and daily peaks using recorded 2004 hourly loads reported to FERC by SCE and SDG&E, and a three-day moving average of daily maximum temperatures weighted by the number of air conditioning units estimated to be in each region. The estimation included weekdays from June 15 through September 15, on which the weighted average maximum temperature was above 75 degrees in SCE, or 70 degrees in SDG&E service territories.

Figures 3 and 4 show the 2004 relationship between temperature and load and the estimated weather response function for SCE and SDG&E, respectively. By calculating the slope, the staff determined that a one degree increase in weighted average temperature equates to a 317 MW increase in peak demand for SCE and a 66.5 MW increase for SDG&E.

Figure 3: SCE Load vs. Temperature Relations

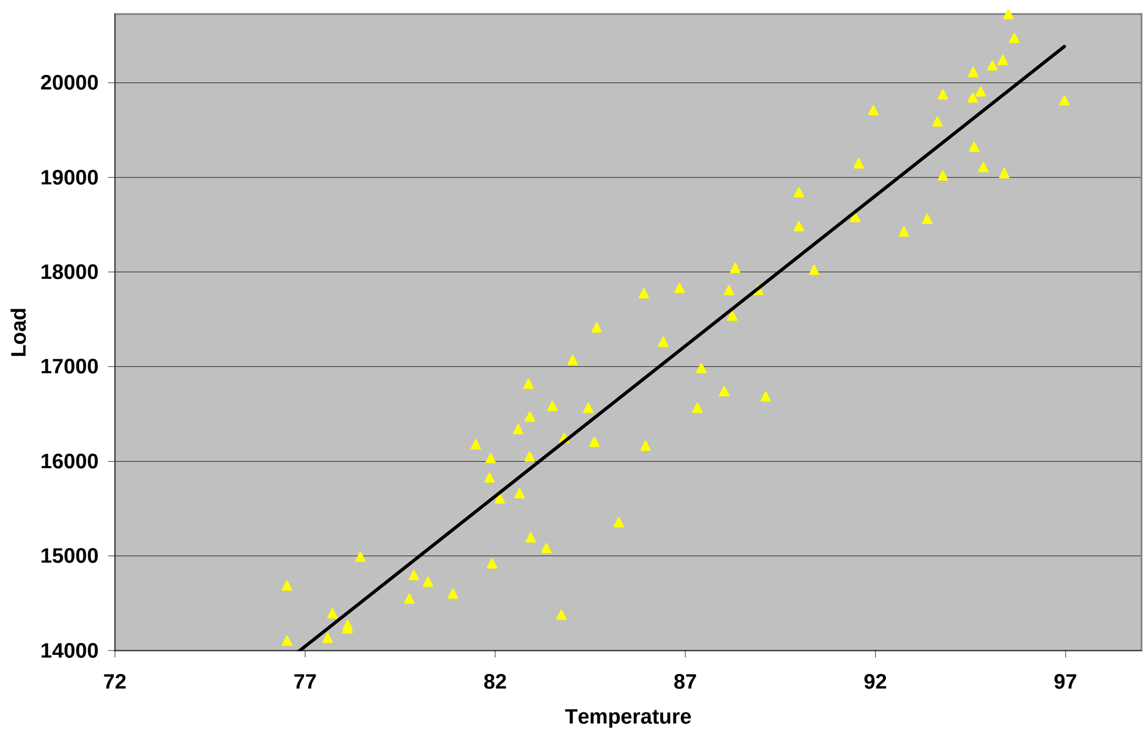
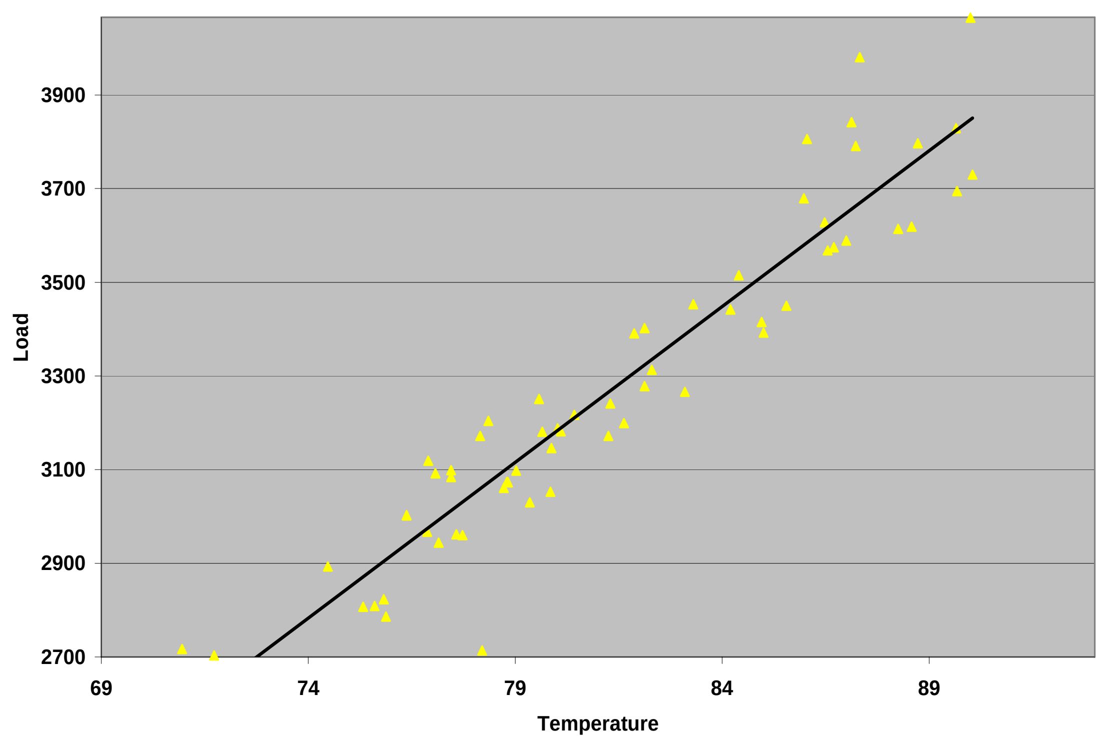


Figure 4: SDG&E Load vs. Temperature Relations



The staff then compared the weighted average temperature for the 54 years of historic weather data to calculate a distribution of summer 2007 peak demand possibilities. For example, if the weighted average temperature used in the demand forecast for SP26 is 98 degrees and the weighted average temperature in 1976 was 101, the resulting 2007 peak demand increase using 1976 temperature data would be 1,150 MW ((317+66.5) * (101-98)) for the SP26 region. Finally, the staff applied the change in demand for each recorded peak temperature over the 54 year period to develop a peak demand distribution. The resulting probabilistic graph for Southern California is presented in Figure 5. The chart characterizes the probability of aggregated load occurring for the whole Southern California region.

Figure 5: Probability of Demand
California ISO SP26 Summer 2007

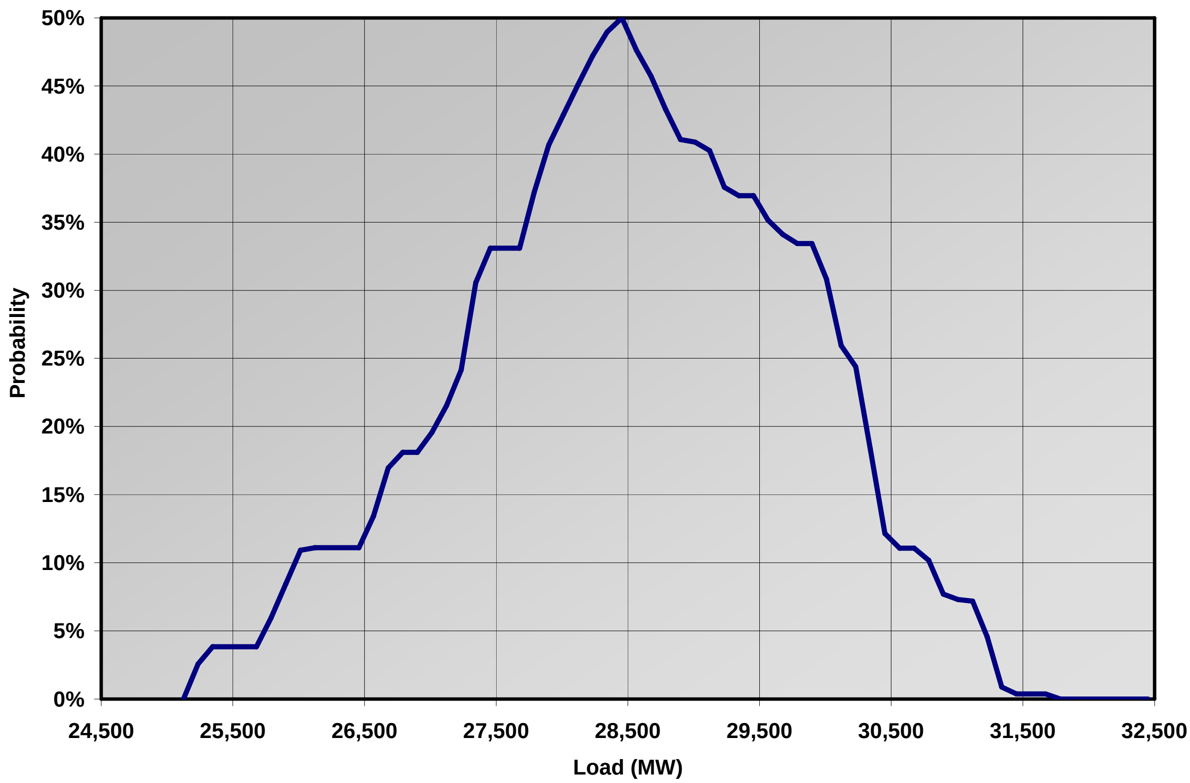


Figure 5 shows that the range of SP26 demand in 2007 could be as low as 25,125 MW or as high as 31,785 with a ‘most likely’ demand of 28,455 MW. While the forecast could equally be higher or lower than the mean, the risks associated with the higher options are more relevant for planning considerations.

Probability of Generation Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. Energy Commission staff calculated potential 2007 outages using actual 2002 thru 2006 daily outage totals for the summer peak period provided by the California ISO. This set of data was statistically processed, and the results are presented in Figure 6.

Figure 6: Probability of Generation Forced Outages California ISO SP26 Summer 2007

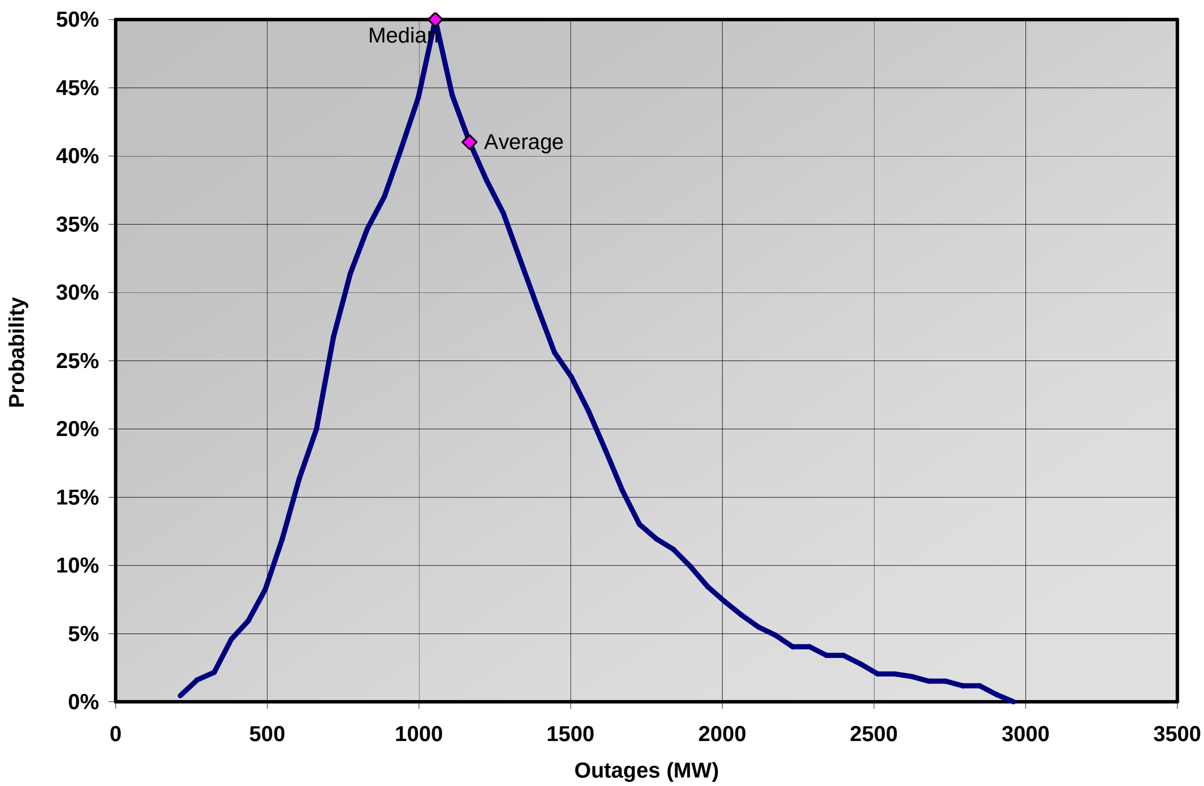


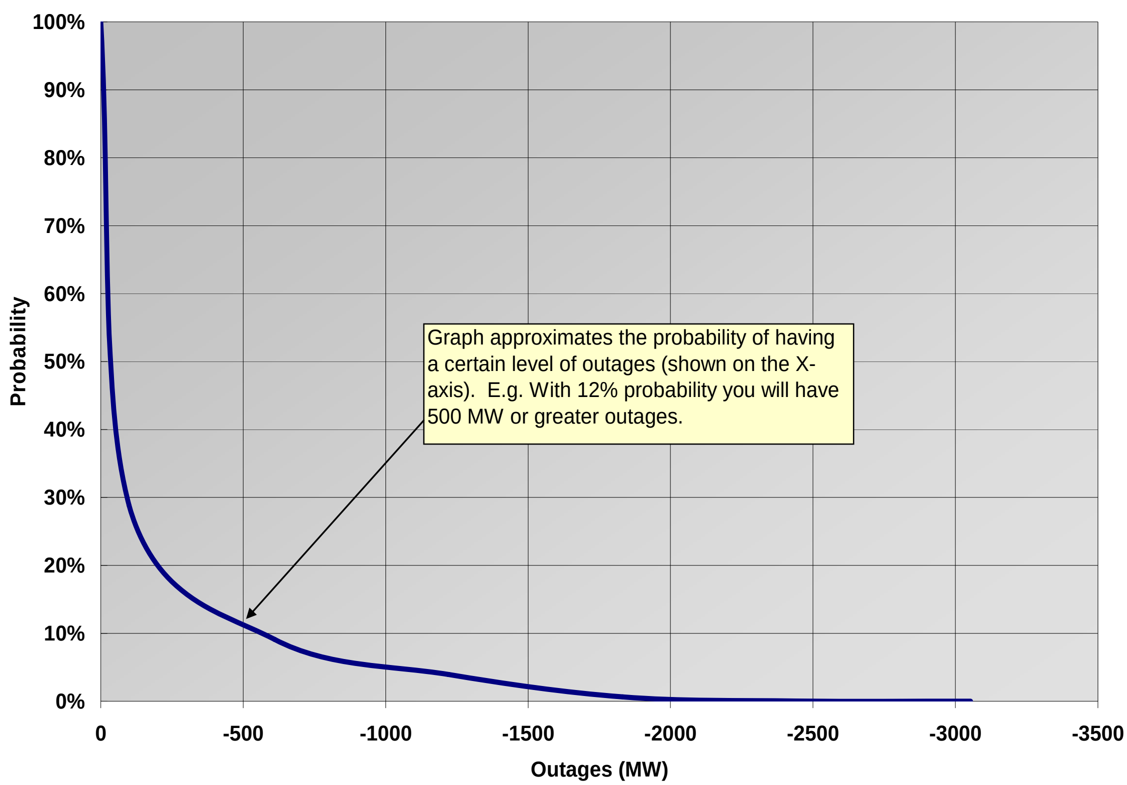
Figure 6 shows the range of SP26 forced outages in 2007 could be as low as 213 MW or as high as 2,960 MW, with a 'most likely' outage number of 1,054 MW. Again, the risks associated with the higher outages are the more relevant factors for resource planning considerations. The staff estimates a ten percent probability that forced outages will be as high as 1,894 MW, and a three percent probability that they will be as high as 2,400 MW.

Probability of Transmission Line Forced Outages

A major transmission line outage can also have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW deviation in the day-ahead peak demand forecast, required the California ISO to issue a Transmission Emergency notice requesting utilities in SP26 reduce demand by curtailing 900 MW of firm load and 800 MW of voluntary interruptible load for about 35 minutes.

The staff included the effects of major transmission outages in the probabilistic analysis for this report. To calculate the overall impact of these failures on the SP26 region, the staff used data obtained by subpoena from the California ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this methodology is that it may omit short duration outages that are not visible at the time the transfer capacity is reported. For example, a line that trips off at 5 minutes after the hour and is restored 50 minutes later would not be visible in the dataset. Figure 7 provides the range of transmission outages observed from May 15 thru September 15 for the years 2003 thru 2005.

Figure 7: Probability of Transmission Line Forced Outages
California ISO SP26 Summer 2007



Probability of Maintaining Minimum Required Operating Reserves

Calculating generation and transmission availability and comparing the sum against a complete range of electricity demand results in a probabilistic assessment of resource adequacy. Using the Monte Carlo method, 5,000 cases of different resource and demand scenarios are developed for summer 2007. Each case is then reviewed to determine whether resources are sufficient to meet demand plus minimum operating reserves. The SAM-A model conducts the calculations in the following four major steps:

1. Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor takes a random value from its respective range of possible values.
2. Evaluation of the adequacy of supply is made for each deterministic case using spreadsheet tables.
3. The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors.
4. The resulting set of cases is statistically processed to calculate:
    a. The probability that there is <u>insufficient</u> capacity to meet the peak demand and maintain a given reserve margin.
    b. The probability that there is <u>sufficient</u> capacity to meet the peak demand and maintain a given reserve margin.

Figures 8 thru 10 provide the probabilities of meeting minimum reserve margins for each of the three studied regions.

Figure 8: Operating Reserve - California ISO Summer 2007

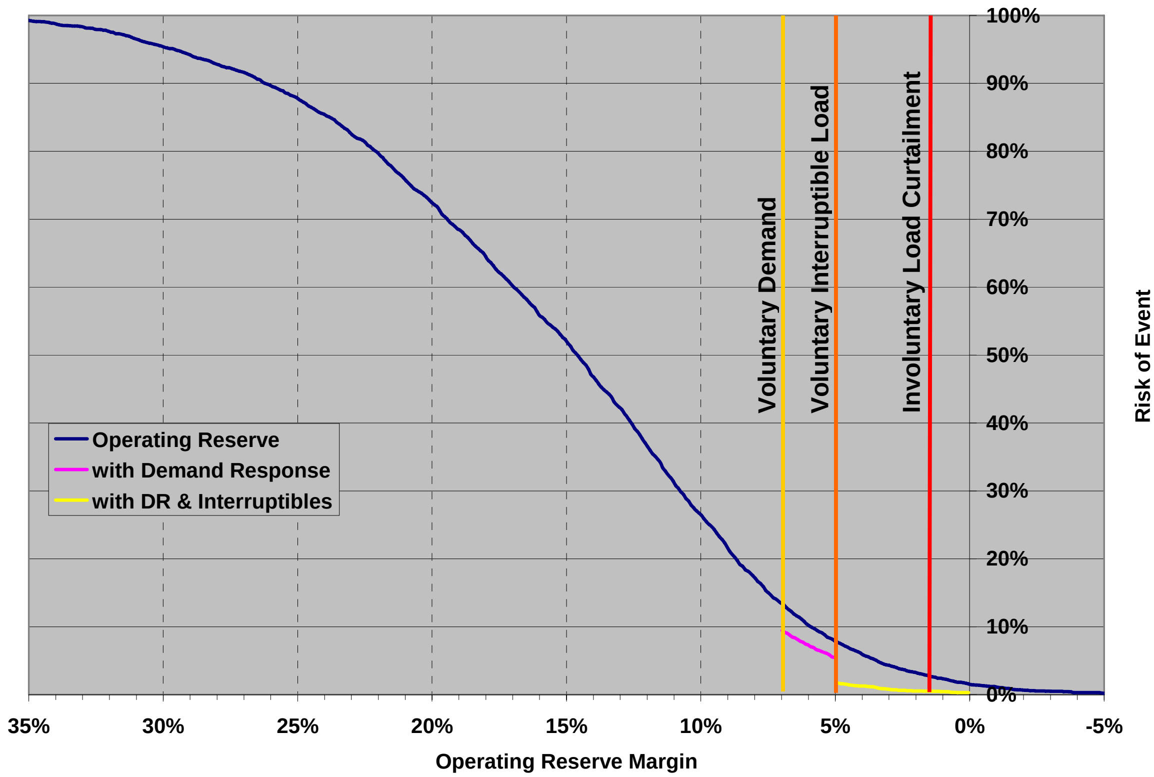


Figure 9: Operating Reserve - California ISO NP26 Summer 2007

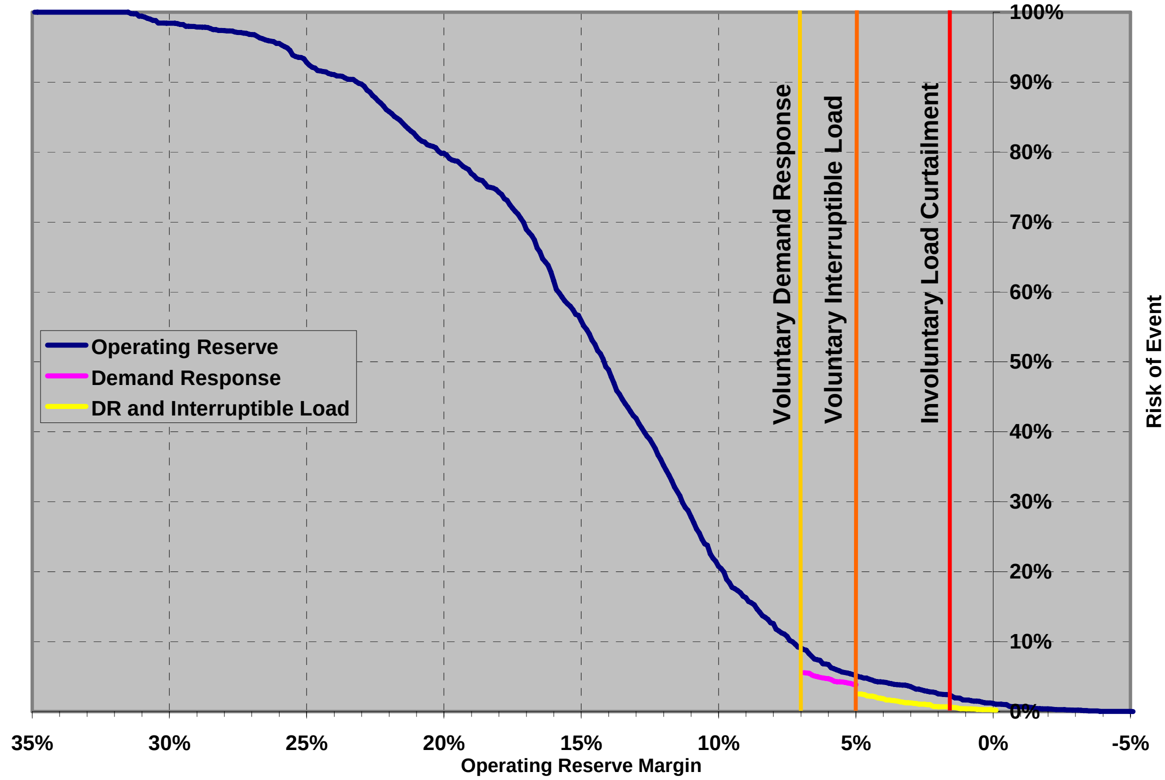


Figure 10: Operating Reserve - California ISO SP26 Summer 2007

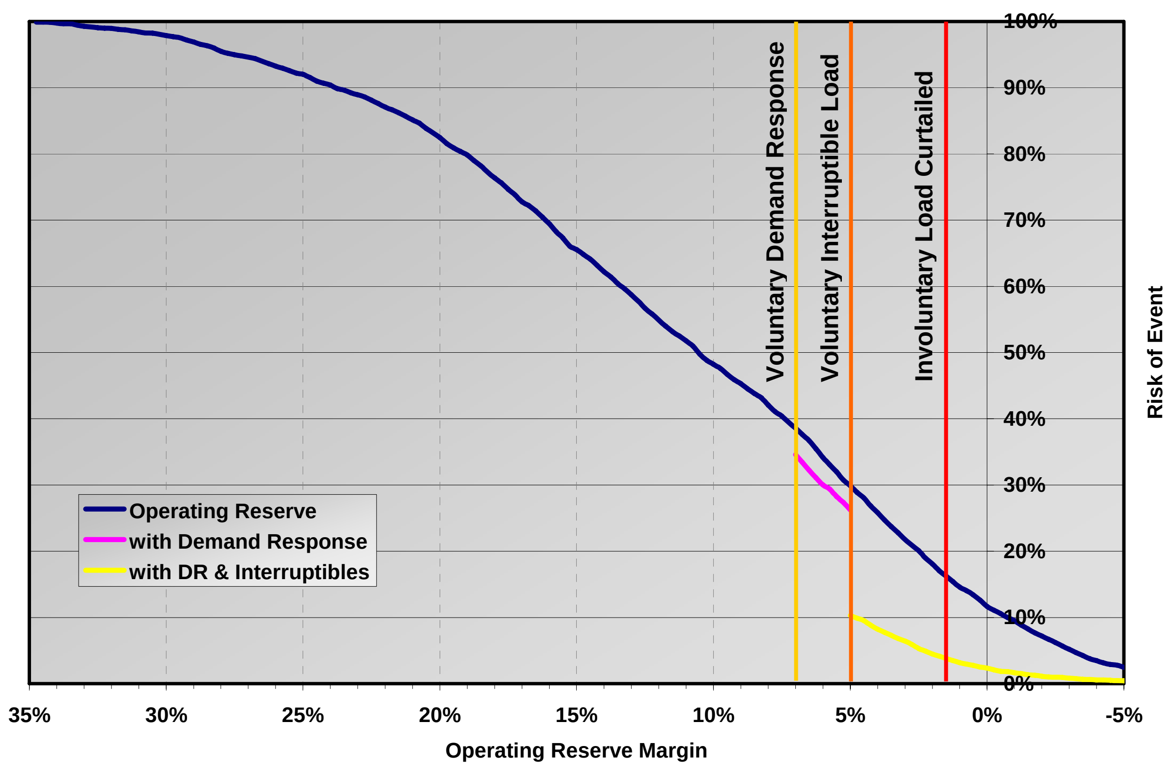
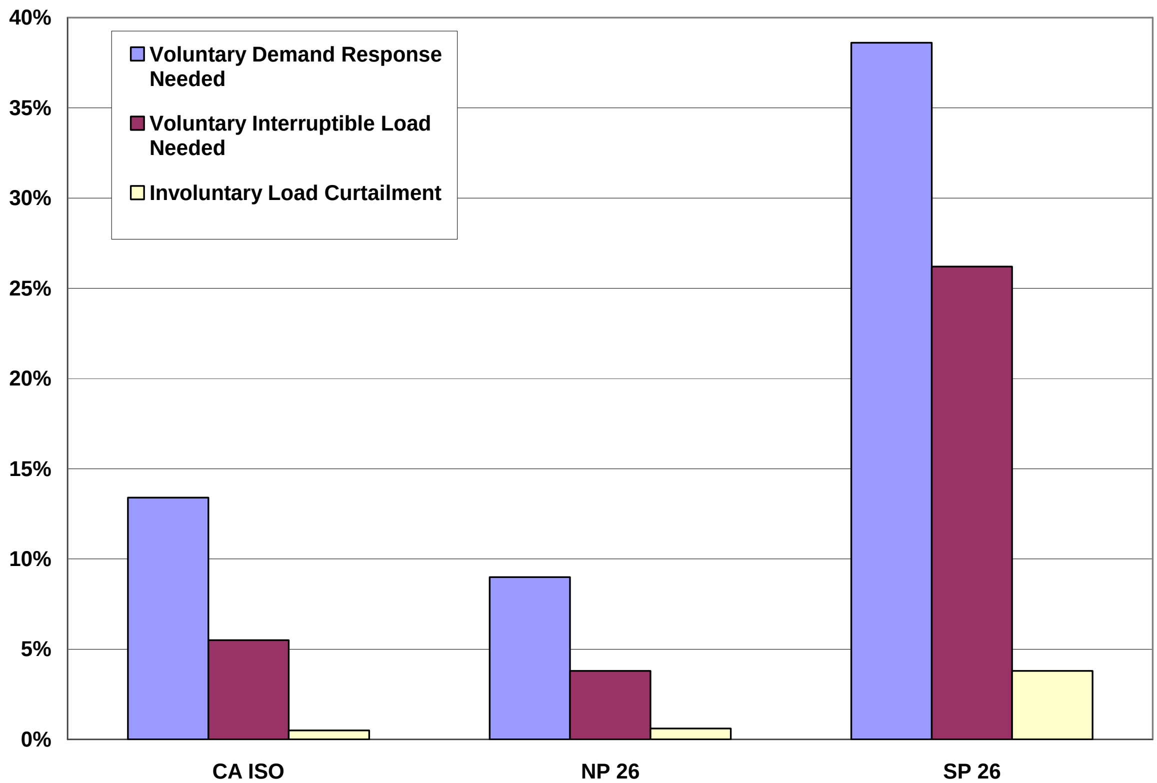


Figure 11 provides a snapshot of the critical points identified in Figures 8 thru 10 for each of the three regions on the peak day of summer 2007. The results can be also interpreted in terms of risk.

The staff estimates that there is a very low risk of involuntary load curtailments in the California ISO and NP26 regions. The risk is higher in the SP26 region, but still significantly lower than the WECC acceptable planning criteria of one event every 10 years, or a 10 percent probability.

The risk of utilizing voluntary demand response and interruptible load programs is much higher, particularly in SP26. This may be considered an acceptable level, however, since the customers enrolled in these programs receive preferential rates or other incentives to provide an extra level of mitigation during peak load conditions.

Figure 11: Risk of Event on the Summer 2007 Peak Day



APPENDIX 1: DETAILED ASSUMPTIONS USED TO CALCULATE PLANNING RESERVE MARGINS

Tables A-1 thru A-4 provide a detailed monthly outlook for each of the four regions to the planning reserve calculation.

Table A-1: 2007 Detailed Monthly Electricity Outlook – Statewide
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	57,897	57,986	58,224	58,553
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	89	238	329	0
4 Net Interchange	13,118	13,118	13,118	13,118
5 Total Net Generation	71,104	71,342	71,671	71,671
6 1-in-2 Summer Temperature Demand (Average)	57,125	59,726	60,344	59,419
7 Demand Response	524	524	524	524
8 Interruptible/Curtailable Programs	1,603	1,603	1,603	1,603
9 Planning Reserve	28.2%	23.0%	22.3%	24.2%

Table A-2: 2007 Detailed Monthly Electricity Outlook – California ISO Control Area
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	46,265	46,354	46,592	46,768
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	89	238	176	0
4 Net Interchange	10,600	10,600	10,600	10,600
5 Total Net Generation	56,954	57,192	57,368	57,368
6 1-in-2 Summer Temperature Demand (Average)	46,148	48,138	48,289	47,858
7 Demand Response	524	524	524	524
8 Interruptible/Curtailable Programs	1,403	1,403	1,403	1,403
9 Planning Reserve	27.6%	22.8%	22.8%	23.9%

Table A-3: 2007 Detailed Monthly Electricity Outlook – California ISO Northern Region (NP26)
(Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	24,417	24,491	24,491	24,491
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	74	0	0	0
4 Net Interchange	500	500	500	500
5 Total Net Generation	24,991	24,991	24,991	24,991
6 1-in-2 Summer Temperature Demand (Average)	20,653	21,098	20,815	20,052
7 Demand Response	322	322	322	322
8 Interruptible/Curtailable Programs	316	316	316	316
9 Planning Reserve	24.1%	21.5%	23.1%	27.8%

Table A-4: 2007 Detailed Monthly Electricity Outlook – California ISO Southern Region (SP26)
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation	21,848	21,863	22,101	22,277
2	Retirements (Known)	0	0	0	0
3	High Probability CA Additions	15	238	176	0
4	Net Interchange	10,100	10,100	10,100	10,100
5	Total Net Generation	31,963	32,201	32,377	32,377
6	1-in-2 Summer Temperature Demand (Average)	26,044	27,612	28,050	28,375
7	Demand Response	202	202	202	202
8	Interruptible/Curtailable Programs	1,087	1,087	1,087	1,087
9	Planning Reserve	27.7%	21.3%	20.0%	18.6%

Resources

Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 1, 2006. Thermal generation consists of California ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained generation, and Qualifying Facilities (QFs). The merchant thermal generation in SP26 includes 1,080 MW of contracted capacity from units located in Baja California Norte. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. The Non-California ISO generation totals include both thermal and hydro capacity. Table A-5 provides a more detailed breakout of existing generation.

Table A-5: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal & QF	16,620	15,903	32,523
Municipal Thermal	751	182	933
IOU Retained Thermal	3,430	2,393	5,823
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**21,848**	**24,417**	**46,265**
Non-CA ISO	6,523	5,109	11,632
STATEWIDE TOTAL			**57,897**

Dependable hydro capacity at peak does not significantly change between a wet and a dry water year even though the historic record shows that dry conditions can have a significant impact on available energy production. The estimate of dependable hydro capacity that the staff uses is based on low water year conditions and would only be revised slightly upward in an extremely wet year to account for additional run-of-river capacity that could be produced in June and early July by additional runoff. The low precipitation conditions experienced this last winter are not expected to affect peak hydro capacity.

Additions and Retirements

Table A-6 provides a listing of the dependable capacity of all additions and retirements included in the 2007 outlook. The Long Beach repowering and four SCE peaking generation plants are included in the deterministic and probabilistic tables. However, if the summer peak occurs prior to August 1, or the construction of these plants is delayed, some or all of their capacity may not be available.

Table A-6: 2007 Additions and Retirements

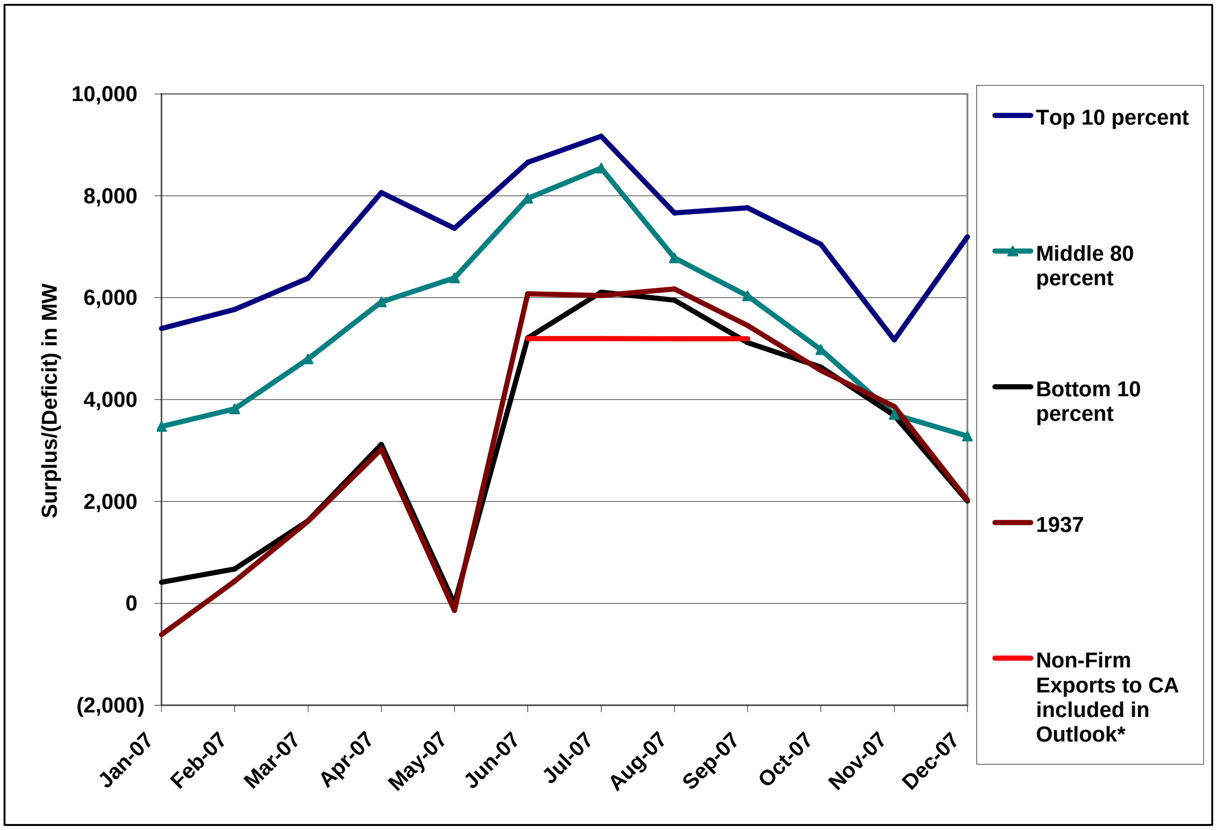
CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
MM Lopez Energy	6	Online	Midsun Generation	22	Online
Otay 3	4	Online	Lake Mendocino Hydro	3	May-07
Rancho Penasquitos	5	Online	Buena Vitsa Wind	3	May-07
Long Beach Repower	238	Jul-07	Fresno Cogen Expansion 2	23	May-07
SCE Regional Peakers	176	Aug-07	Bottle Rock Power	20	May-07
	429		Marina	3	May-07
				74	
Retirements (Known)			**Retirements (Known)**		
Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
			Roseville Energy Park	153	Aug-07
				153	

Net Interchange

Energy Commission staff determined that there is a sufficient quantity of surplus capacity in neighboring regions to meet the net interchange estimates detailed below. Figure A-1 provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest by various water conditions. Even in the driest year on record (1937), there is enough surplus capacity in the region to meet the interchange assumption included in the outlook.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the *WECC Summary of Estimated Loads and Resources Report* issued in June 2006.

Figure A-1: 2007 Forecast of Northwest Regional Surplus/Deficit by Water Year



Based on 2006 BPA White Book 1-Hour Capacity in Megawatts

Tables A-7 thru A-10 detail the individual components of net interchange for each of the four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

Table A-7: Statewide Net Interchange

Northwest Imports (COI)[1]	4,000
Southwest Imports[1]	4,100
Pacific DC Intertie (California ISO)[1]	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

Table A-8: California ISO Net Interchange

California ISO Share of NW Imports (COI)[1]	2,300
WAPA Central Valley Imports	1,200
Southwest Imports[1]	4,100
Pacific DC Intertie (California ISO) [1]	2,000
Net LADWP Control Area Interchange	1,000
Total	**10,600**

Table A-9: NP26 Net Interchange

California ISO Share of NW Imports[1]	2,300
WAPA Central Valley Imports	1,200
Path 26 Exports	(3,000)
Total	**500**

The SP26 net interchange import numbers in Table A-10 include increases in the Southwest imports by 400 MW above 2005 observed levels to account for capacitor upgrades on the Palo Verde-to-Devers line. The LADWP Control Area interchange value includes wheeled power to other municipal utilities served by the California ISO.

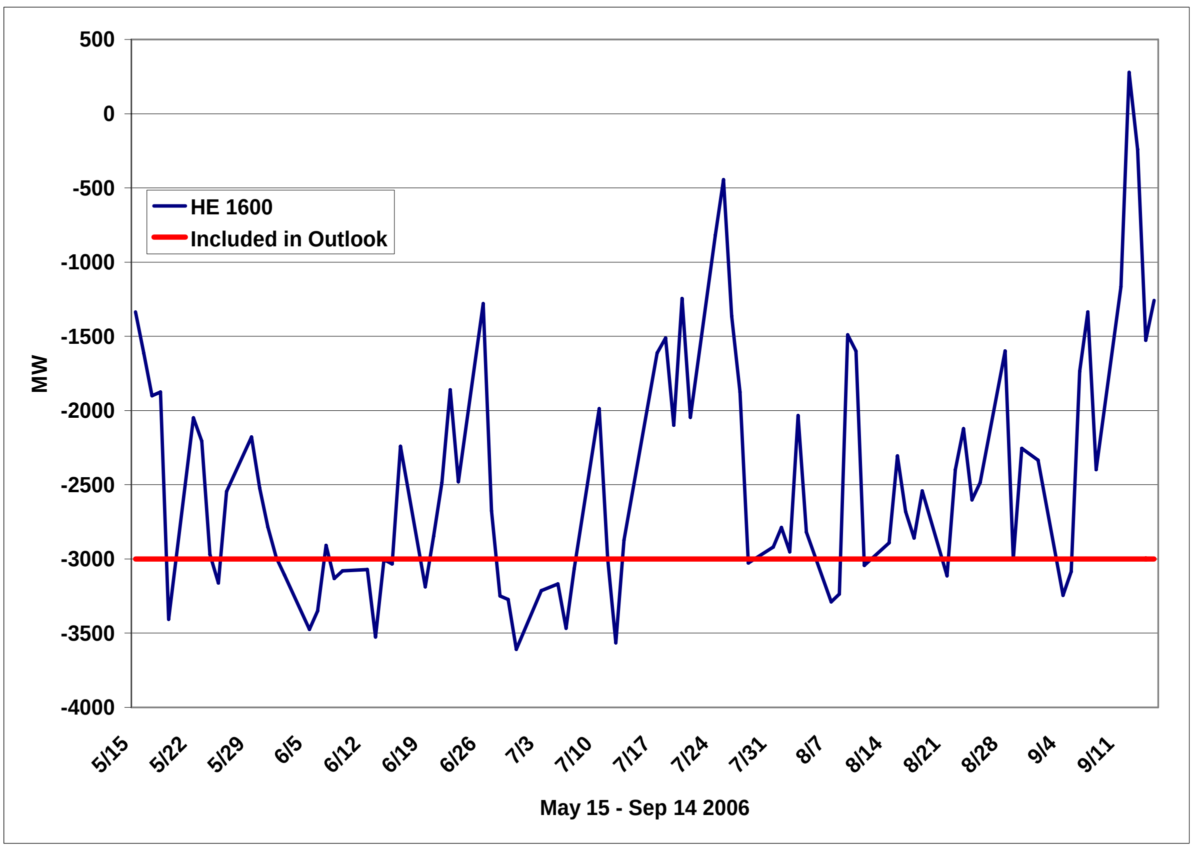
Table A-10: SP26 Net Interchange

Path 26	3,000
California ISO Share of Pacific DC Intertie[1]	2,000
Net SW Imports[1]	4,100
Net LADWP Control Area Interchange	1,000
Total	**10,100**

[1] Imports assumed to carry reserves as transmission is the limiting factor.

Tables A-9 and A-10 include 3,000 MW of Path 26 North to South flows from NP26 to SP26. The export reflects the greater need of capacity in SP26 than NP26, but does not imply that it is contractually obligated to be delivered into SP26. This is a topic that the staff has identified for additional analysis to improve the modeling of this assumption. Figure A-2 provides the actual flows on Path 26 for the hour ending 1600 during summer 2006. Negative numbers indicate North to South flows and positive numbers are South to North. There is clearly a wide range of variation in the flows from one day to the next and, in the case of the heat storm period of July 24 and 25, the North to South flow was less than 1,000 MW during the unusual periods of extreme temperatures in Northern California.

Figure A-2: Path 26 Summer Flows HE 1600



Demand

1-in-2 Summer Temperature Demand (Average)

The demand forecast is the Statewide 1 in 2 Electric Peak Demand by Load Serving Entity (MW), Base Case in the most recent adopted Energy Commission demand forecast[1] as updated for the Investor Owned Utility portion in June 2006[2]. Complete documentation of assumptions and methodologies are included in the above reports.

Demand Response and Interruptible Programs

There are several mitigation measures available to the California ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. Tables A-11 and A-12 detail the subscribed and expected IOU demand response and interruptible programs that are established at the CPUC and/or have been contracted by an IOU. Expected values are obtained by calculating the percentage of each subscribed program that was observed when previously called and applying that percentage to the currently subscribed amount. There is also an additional 110 MW of demand response from pumping load in SP26 that is not included in the PUC filings.

Because several of these programs are new or evolving, and participation may be significantly different than projections, the staff used the 2006 demand response estimate for the summer 2007 until actual data can be obtained on the performance of these programs. A detailed explanation of the demand response programs identified in Tables A-11 and A-12 follows:

Demand Response Programs

CPP. Critical Peak Pricing: CPP rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

DBP—Demand Bidding Program: Participants are paid an incentive for load reductions during curtailment events that are “bid” in to the utility a day in advance. There is no penalty for not bidding or not fulfilling the bid obligation.

CAL-DRP—California Demand Reserves Partnership: Program aggregators provide a contracted amount of load reduction during curtailment events by aggregating participant load reductions. Aggregators are paid a monthly capacity reservation charge for contracted load reduction amounts and an additional energy payment for consumption avoided during curtailment events.

C/I 20/20—20/20 for Commercial/Industrial customers (SDG&E only): A 20 percent bill credit given to customers who reduce on-peak consumption by an average of 20 percent or greater over all critical peak days.

BEC—Business Energy Coalition: A pilot program in the PG&E service territory operated in partnership with The Energy Coalition, participants are paid a per kW incentive to reduce load during curtailment events. The Energy Coalition works with participating customers to develop customized load reduction strategies.

Interruptible Load Programs

I-6— SCE Traditional non-firm rate: provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

E-19/E-20—PG&E traditional non-firm rates: provide discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

AL TOU CP—SDG&E critical peak rate: On-peak energy charges increase to $1.80/kWh during “critical peak” events, defined as Stage 2 or 3 system conditions.

BIP—Base Interruptible Program: Relatively new interruptible program that offers demand charge credits for load subject to interruption during system emergencies. Significant per kWh penalties apply for non-compliance.

ACCP—Air Conditioner Cycling Program (SCE only): Residential and small - to medium-sized commercial and industrial customers receive a bill incentive to allow SCE to remotely cycle their AC during system emergencies or high demand periods. The incentive varies based on the percent time the customer is willing to have his equipment cycled off.

OBMC—Optional Binding Mandatory Curtailment: Offers blackout avoidance during rotation outages for up to a 15 percent reduction in circuit load during events.

RBRP—Rolling Blackout Reduction Program (SDG&E only): Offers energy credits for load reductions—obtained through self-generation—during Stage 3 system conditions. Fifteen minute response is required.

AP-I—Agricultural and Pumping Interruptible (SCE only): Provides energy credits on consumption above the contracted firm service level in exchange for emergency reductions. Per kWh penalties apply for non-compliance.

“Emergency” CPP and DBP—these programs operate the same as the CPP and DBP programs except that notification to customers is made day-of instead of day ahead. Incentives reflect the higher value of the load reduction.

Smart Thermo—Smart Thermostat (SCE and SDG&E): Customers with communicating, programmable thermostats receive a bill incentive to allow the utilities to set their thermostats higher during periods of high demand or system emergencies.

Table A-11: IOU Subscribed Demand Response and Interruptible Programs

Demand Response Programs		Subscribed	
	SCE	SDG&E	PG&E
CPP Programs	2	15	45
DBP	181	31	205
CAL-DRP	160	5	248
CI 20/20 or BEC		51	10
Demand Response Sub-Total	**343**	**102**	**508**
Interrruptible Load Programs			
I-6 or E-19/E-20	699		300
AL TOU CP		15	
BIP	101	8	27
ACCP	424	12	
OBMC/RBRP	10	65	14
AP-I/Emergency CCP/DBP-E/DBP-E	72	12	
Smart Thermo		2	
Interruptible Sub-Total	**1306**	**114**	**341**
Total	**1649**	**216**	**849**

Source: IOU filings under PUC R.00-10-002 and R.02-06-001.

Table A-12: IOU 2007 Expected Demand Response and Interruptible Programs

Demand Response Programs		Expected	
	SCE	SDG&E	PG&E
CPP Programs	0.9	5.8	28.3
DBP	37.4	0.7	64.8
CAL-DRP	35.4	3.2	226.0
CI 20/20 or BEC		8.7	3.2
Demand Response Sub-Total	**74**	**18**	**322**
Interrruptible Load Programs			
I-6 or E-19/E-20	585.8		276.8
AL TOU CP		1.7	
BIP	60.8	0.2	25.8
ACCP	353.7	8.6	
OBMC/RBRP	10	25.2	13.5
AP-I/Emergency CCP/DBP-E/DBP-E	34	5.6	
Smart Thermo		1.4	
Interruptible Sub-Total	**1044**	**43**	**316**
Total	**1118**	**61**	**638**

Source: IOU filings under PUC R.00-10-002, R.02-06-001 and D.06-03-024.

Planning Reserve Margin

The planning reserve margin is calculated in a similar manner as in CPUC resource adequacy proceedings. The formula used to calculate the planning reserve margin is: ((Total Net Generation + Demand Response + Interruptible) / Demand)) – 1.

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[1] *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 - Staff FINAL Report* (CED 2006). Publication # CEC-400-2005-034-SF-ED2. [http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF]

[2] *Staff Forecast of 2007 Peak Demand, June 2006.* CEC-400-2006-008-SF [www.energy.ca.gov/2006publications/CEC-400-2006-008/CEC-400-2006-008-SF.PDF]